Solar-to-Grid

Trends in System Impacts, Reliability, and Market Value in the United States with Data Through 2020

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Goal: improve decision making through information on the observed market value and grid impacts of solar

Characteristics of Deployed Solar

Utility-Scale (UPV)

EIA Form 860 by Plant (>1 MW)

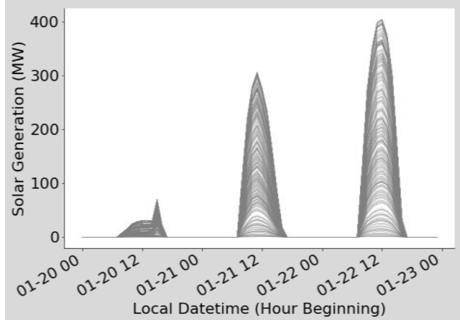
Distributed PV (DPV)

Residential and Non-Residential

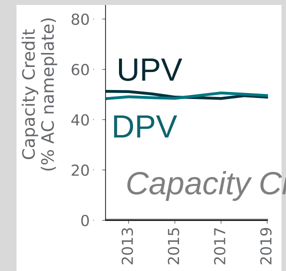
EIA Form 861 by State (<1 MW)

Hourly Solar Generation Profiles

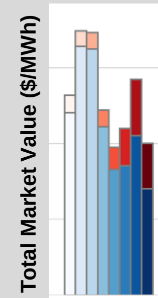
Solar Generation at Individual Plants



Contribution to Reliability



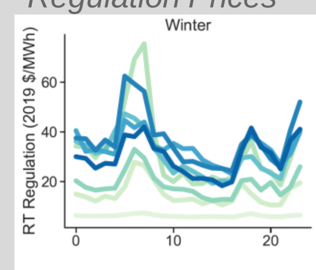
Market Value



Capacity *and* *Energy* *Value*

Bulk System Impacts

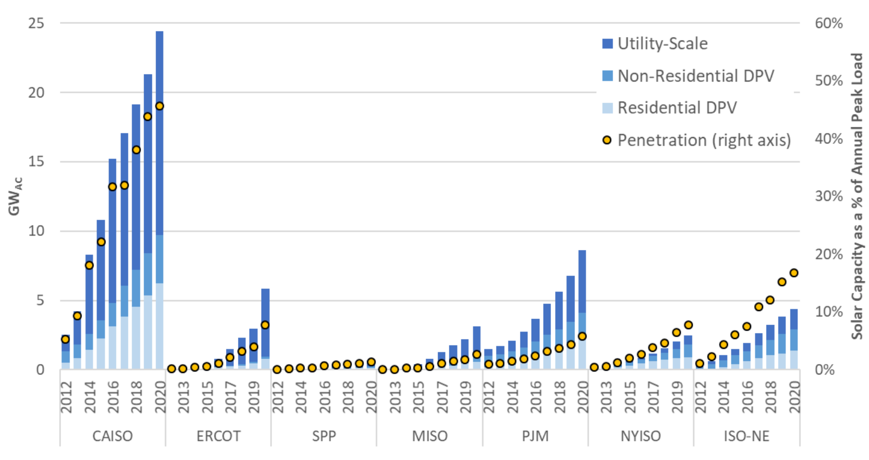
Regulation Prices

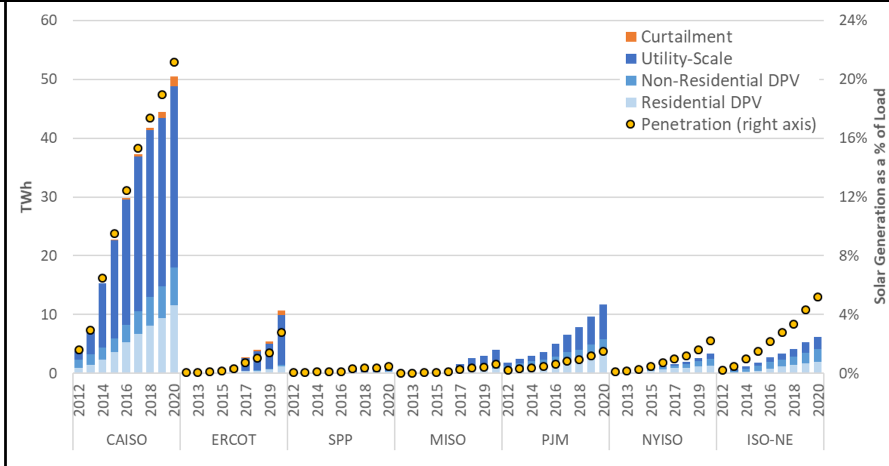


Solar deployment in CAISO far exceeds the level in other ISOs

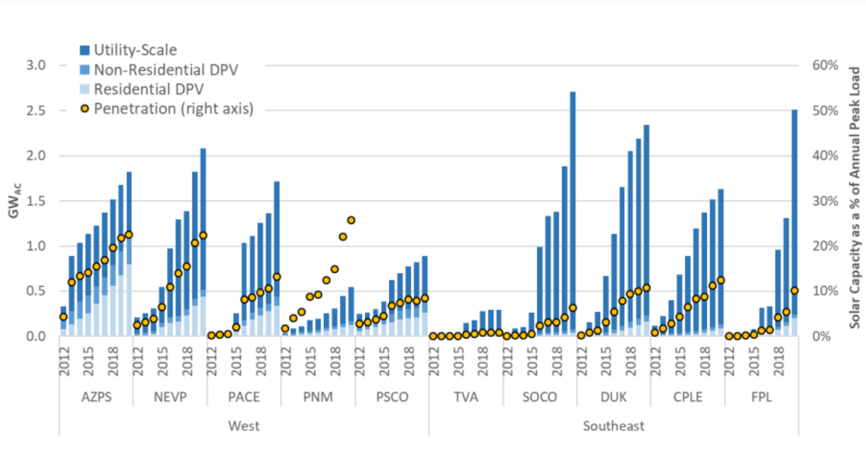
Capacity | **Generation**

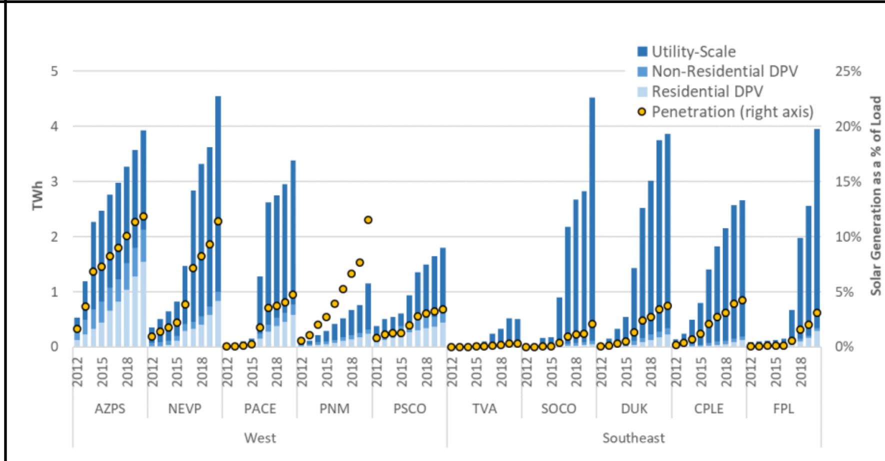
ISOs





Select Utilities

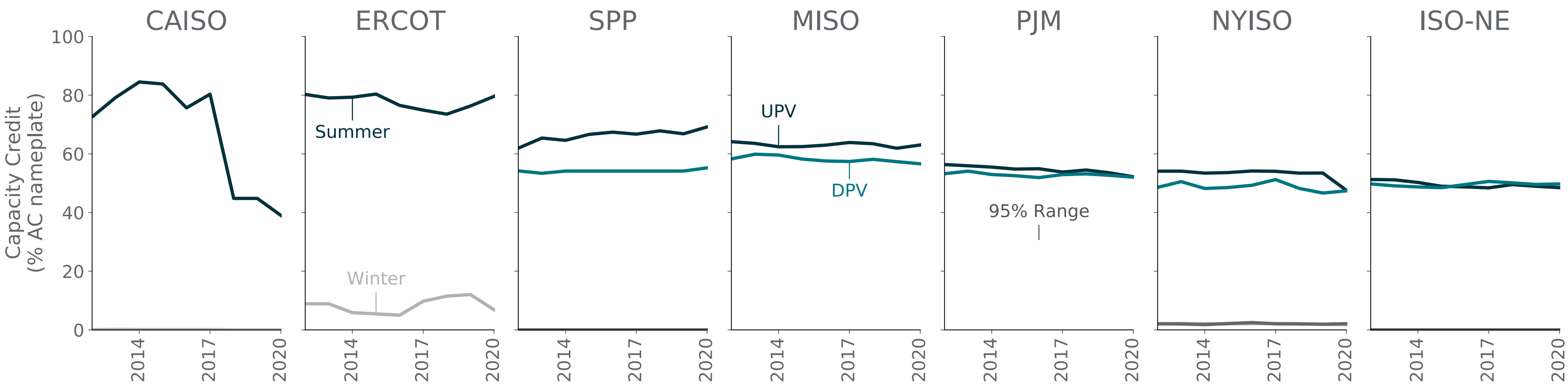




Capacity credit of solar

Average summer capacity credits in 2020 range from 39–80%, capacity credit is near zero in winter

Capacity credit of solar is calculated by methods used by each market. CAISO shifted to an "effective load carrying capability" method in 2018, PJM will do the same for 2023/24, SPP plans to shift in 2023.



Determined at the system level

Determined at the plant level, with shaded area covering capacity credit of 95% of plants

	CAISO	ERCOT	SPP	MISO	PJM	NYISO	ISO-NE
Basis of measurement	ELCC	Average generation in top 20 peak hours	Generation exceedance level during top 3% peak hours	Average generation during peak period	Average generation during peak period	Average generation during peak period	Median generation during peak period
Frequency of measurement	Monthly	Summer, fall, winter, spring	Summer, winter	Summer	Summer	Summer, winter	Summer, winter
Credit varies for UPV vs. DPV?	No	No	Yes	Yes	Yes	Yes	Yes

Market value of solar

Market value approach and assumptions

Energy Value

$$Energy\ Value = \frac{\sum Postcurtailment\ Generation_h * Wholesale\ RT\ Energy\ Price_h}{\sum Precurtailment\ Generation_h}$$

- Plant-level debiased hourly solar generation
- Real-time energy price from nearest pricing node
- Focus on annual value of solar from all sectors

Capacity Value

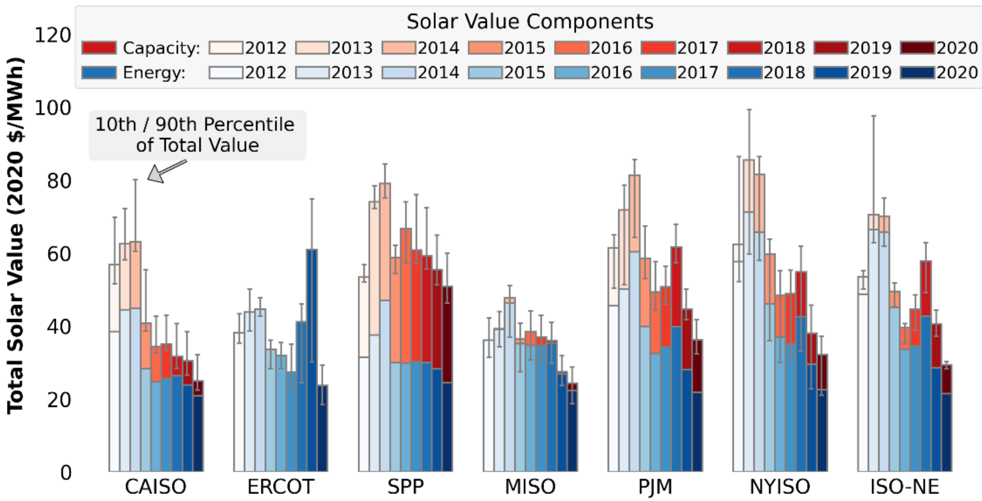
$$Capacity\ Value = \frac{\sum Capacity\ Credit_T * Nameplate * Capacity\ Price_T}{\sum Precurtailment\ Generation_T}$$

- Capacity credit based on plant-level profile; varies by month, season, or year
- Capacity prices from respective ISO region; prices vary by month, season, or year
- Estimate bilateral capacity prices for regions without organized capacity markets
- Focus on annual value of solar from all sectors
- Calculate capacity value for all solar, even if some solar does not participate in capacity markets

- No AS value, REC value, wholesale price effects, or externalities included in market value
- Energy + capacity value represents the marginal value to the power system

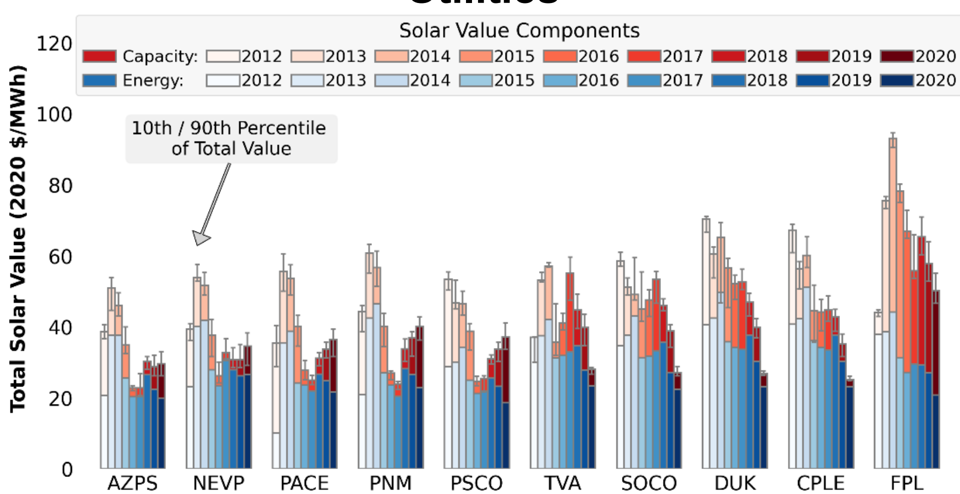
Variations in average energy and capacity prices largely drive differences in the market value of solar

ISOs

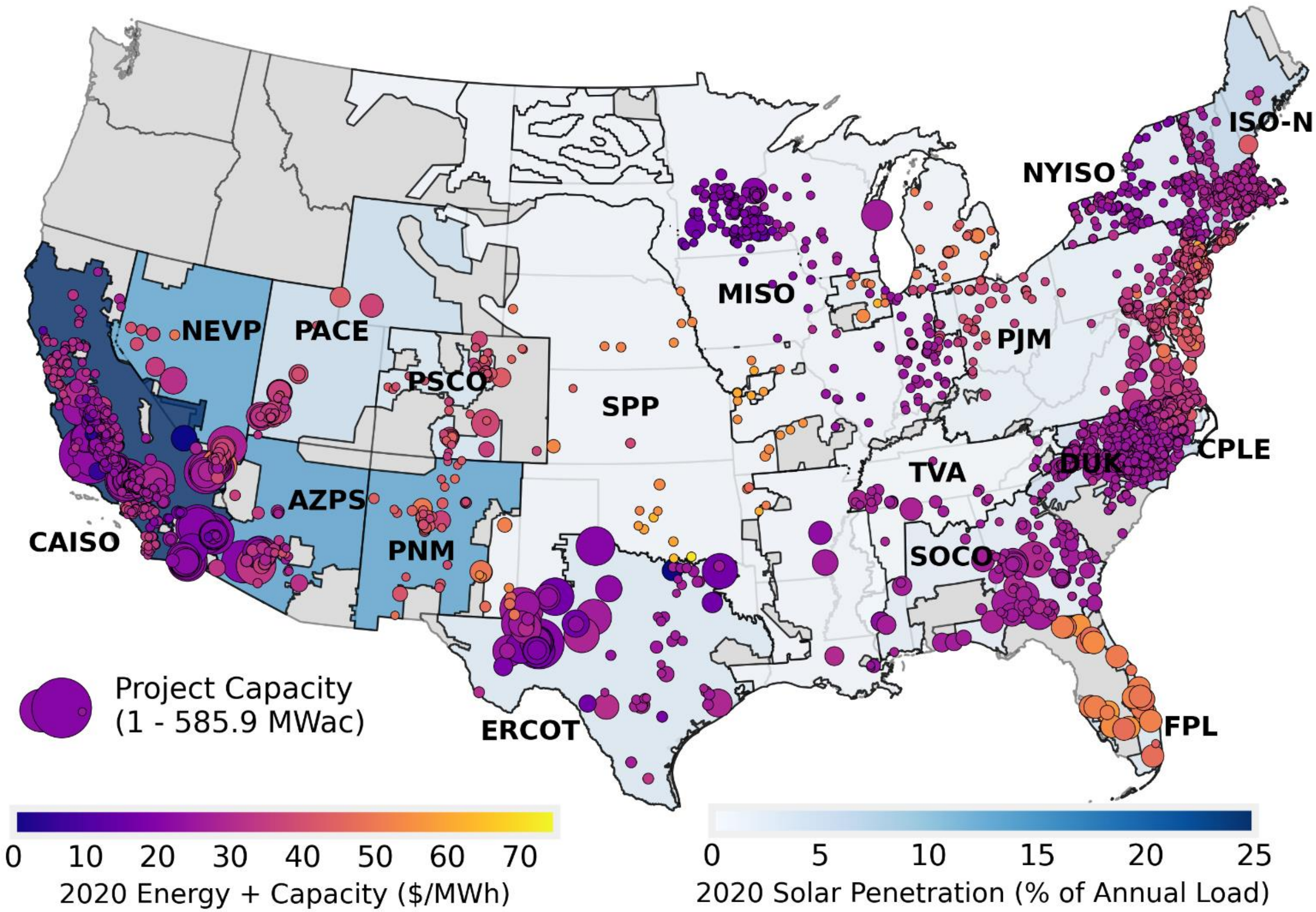


Note: ERCOT's solar market value spiked temporarily in 2019 due to scarcity prices during some summer afternoons

Utilities

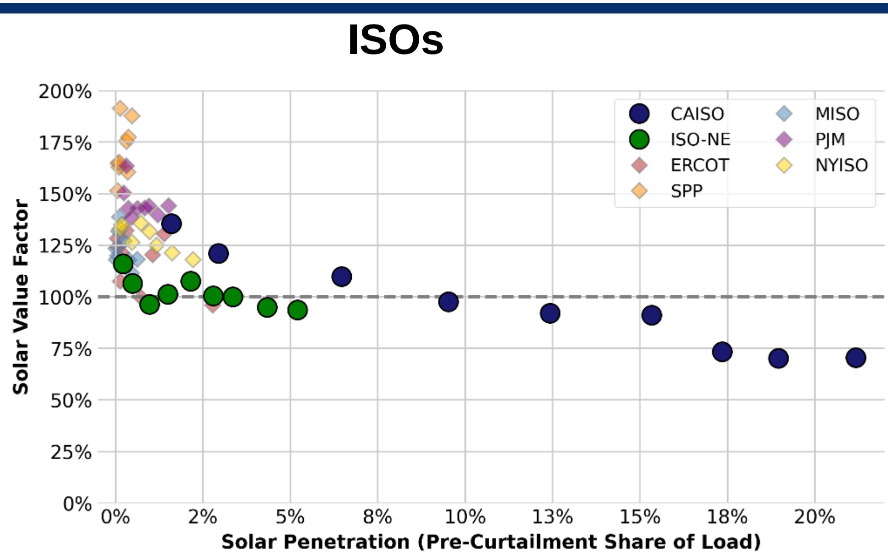


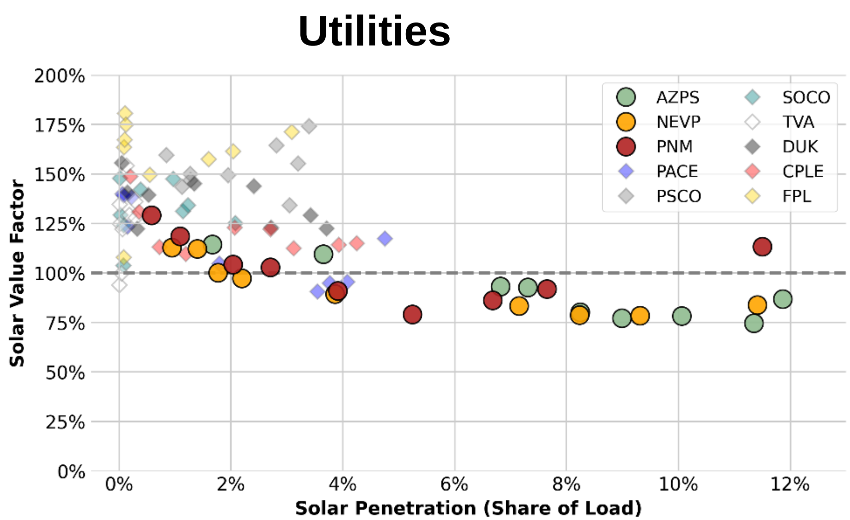
Wholesale market value of solar, by plant in 2020



Note: Only plants larger than 1 MW are shown

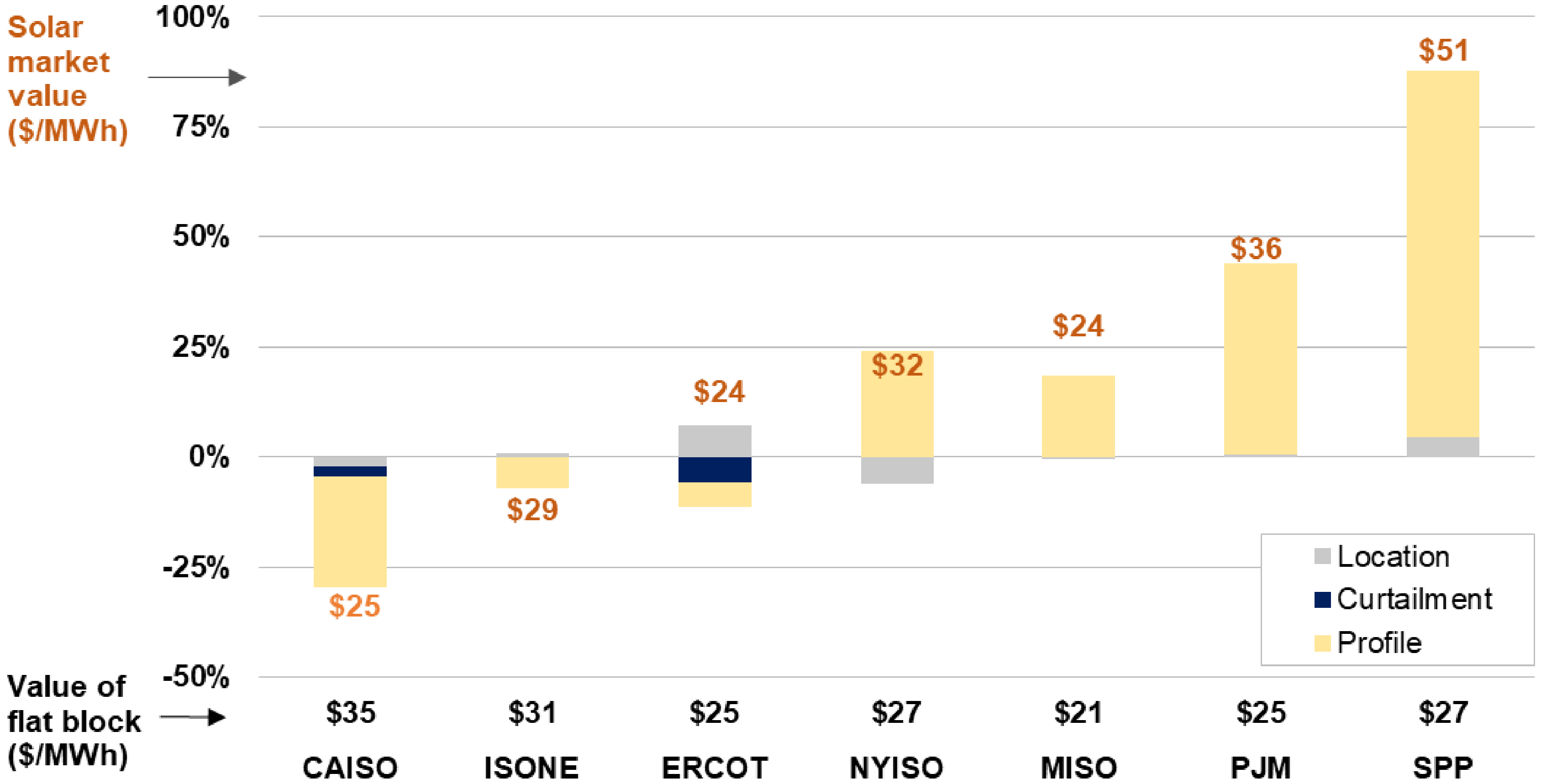
Market value of solar declines with higher solar penetration relative to average prices





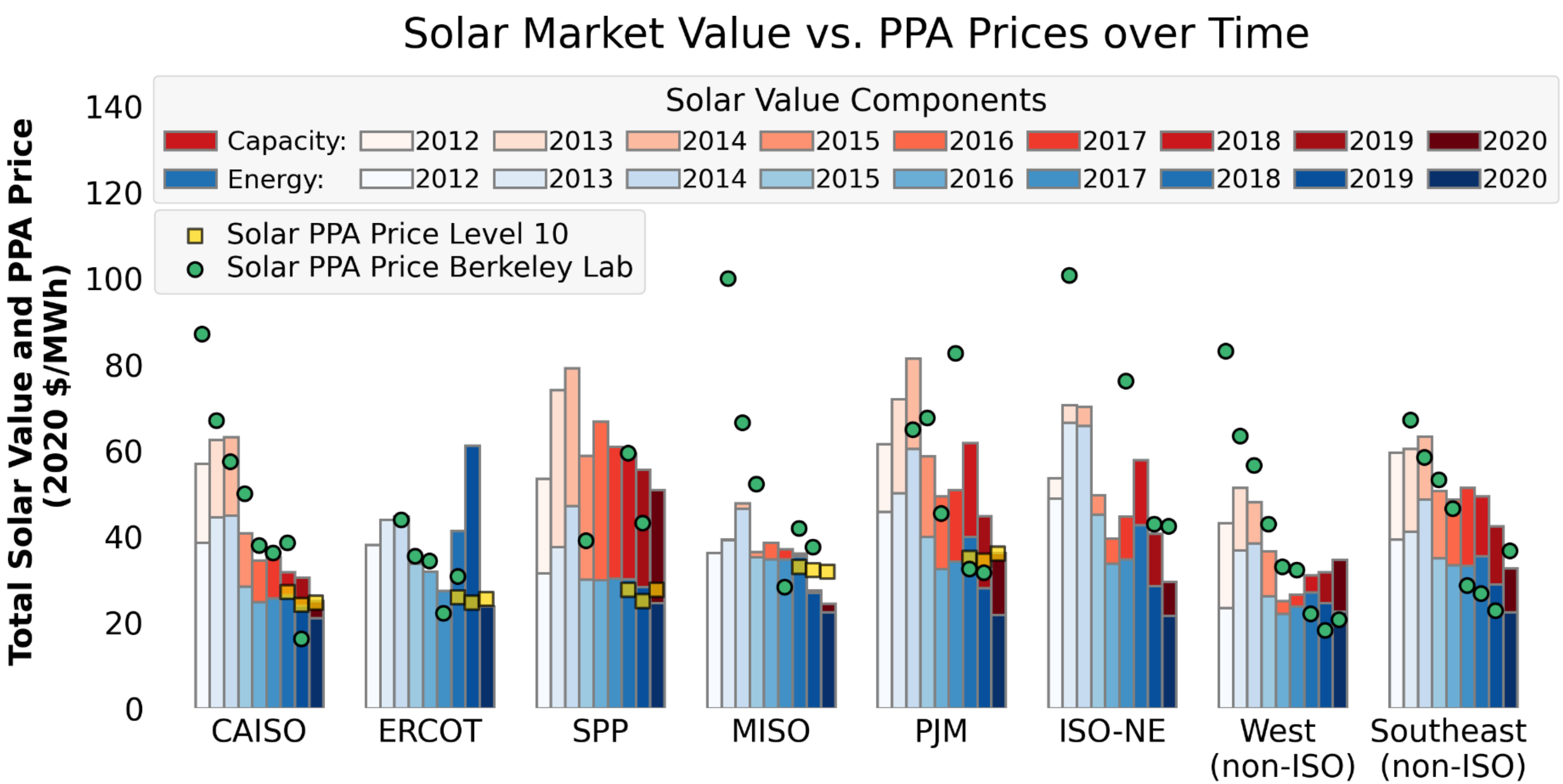
Solar value factor = wholesale market value of solar relative to generalized flat block of power in region; generalized flat block is 24x7 average price across all pricing nodes in region

Market value relative to a flat block is primarily due to the timing of the solar profile, rather than solar location



Note: Flat block is 24x7 average price across all pricing nodes in region

Falling costs have kept pace with declining solar value, more or less maintaining solar's competitiveness



Note:

- *Berkeley Lab's PPA prices are the generation-weighted average levelized PPA prices in real $ by execution date*
- *Level 10 PPA prices represent only the 25th percentile of all offers by offer date*

Analysis of empirical PV+Storage dispatch show moderate wholesale market value premium of storage

PV+Storage business models are diverse and target many different value streams beyond those monetized in wholesale markets

- **Dispatch:** Competitively-set market prices
- **Revenue:** Energy and ancillary services (AS) revenue

Merchant

- **Dispatch:** Regulated peak-load pricing schedules
- **Revenue:** Lower transmission costs; potentially AS revenue

Peak-load reducer

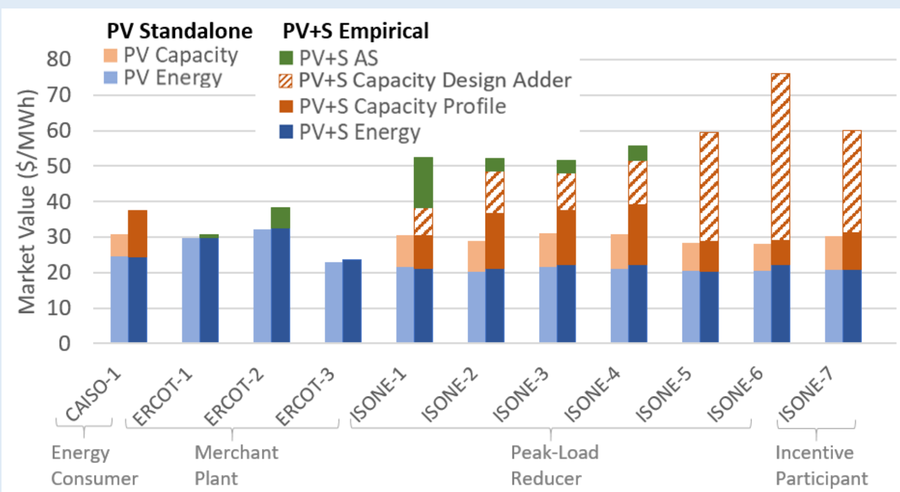
- **Dispatch:** Incentive program rules;
- **Revenue:** Feed-in tariff, renewable energy credits (RECs), tax credits, grants

Incentive participant

- **Dispatch:** Regulated utility tariffs; private operating costs
- **Revenue:** Lower operating costs; resiliency benefits

Large end-user

2020 Wholesale Market Value of PV Standalone and PV+S Profiles



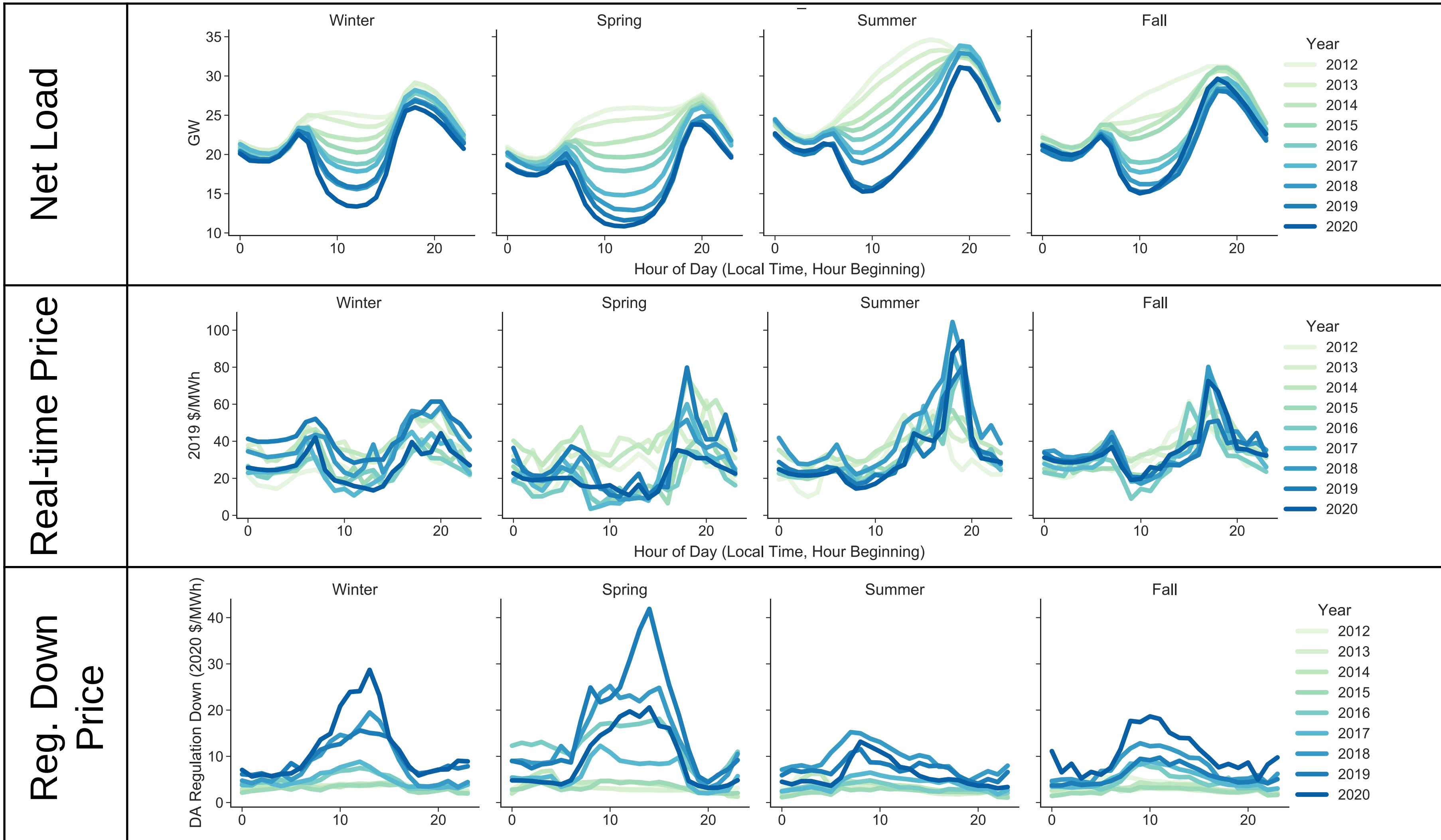
The empirical wholesale storage premium of PV hybrids ranges from $1 to $48/MWh. It is driven by ancillary service revenue and by large capacity credit increases, especially when those are based on a plant's design instead of its empirical generation profile.

Private revenue for PV+S operators can exceed these wholesale benefits:

- Storage premiums can be as high as $100/MWh for peak-load reducers and $30/MWh incentive participants in the ISO-NE regions.
- Total PV+Storage values can approach $150/MWh in both cases.

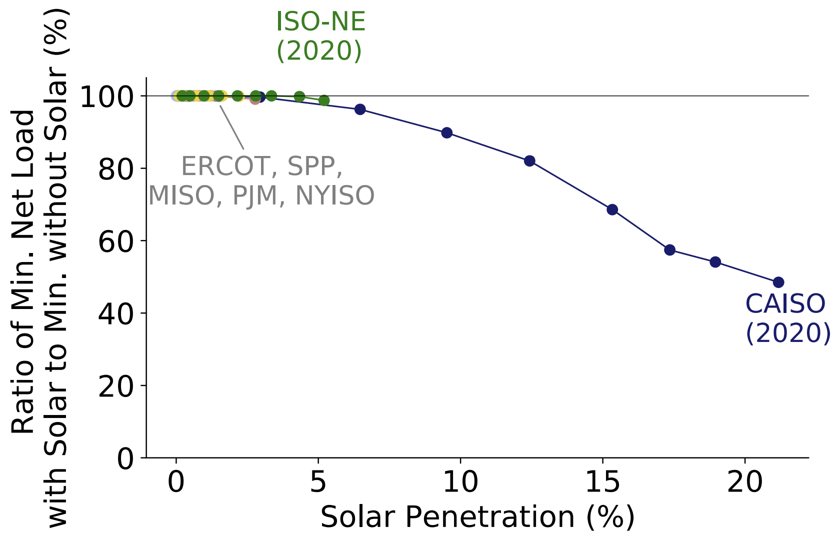
Impact of solar on the bulk power system

Obvious impacts of solar on CAISO net load and wholesale market prices

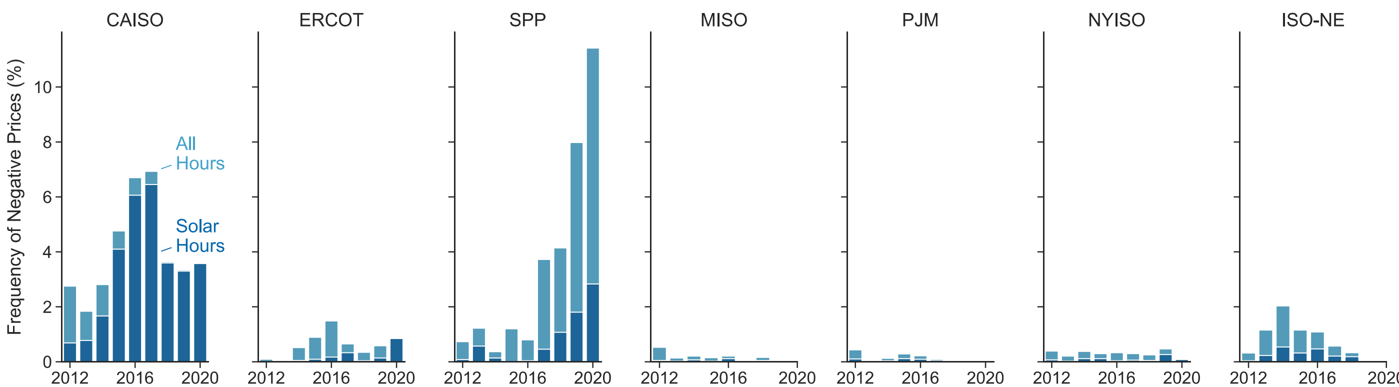


Lower minimum net load due to solar contributes to negative prices in CAISO

Lower minimum net load in CAISO

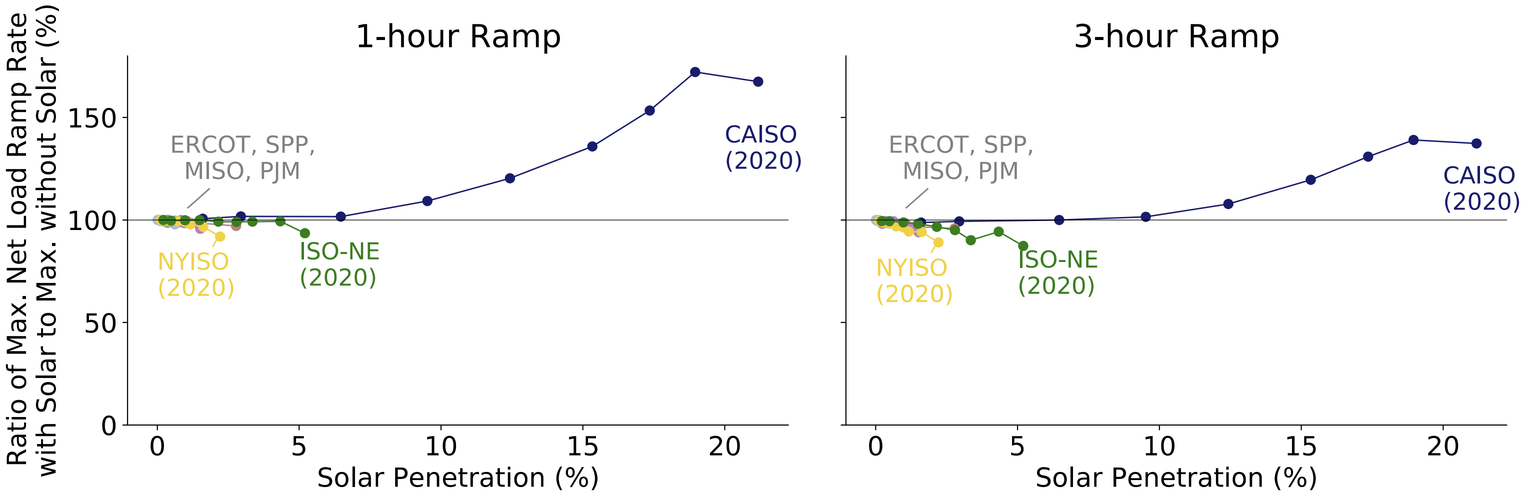


Negative prices occur during solar hours in CAISO

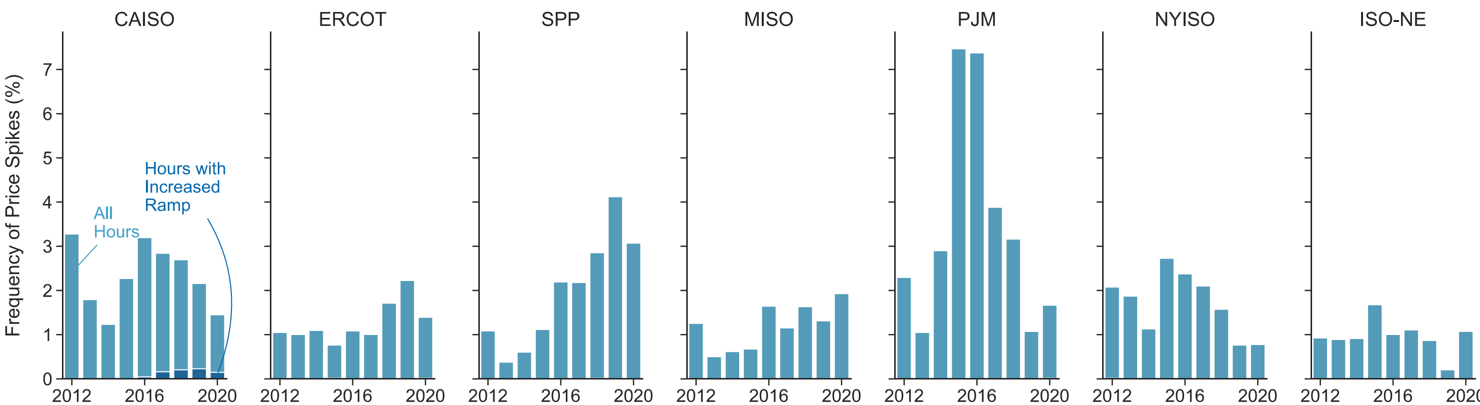


Higher net load ramps due to solar are beginning to contribute to price spikes in CAISO

Higher net load ramp rates in CAISO

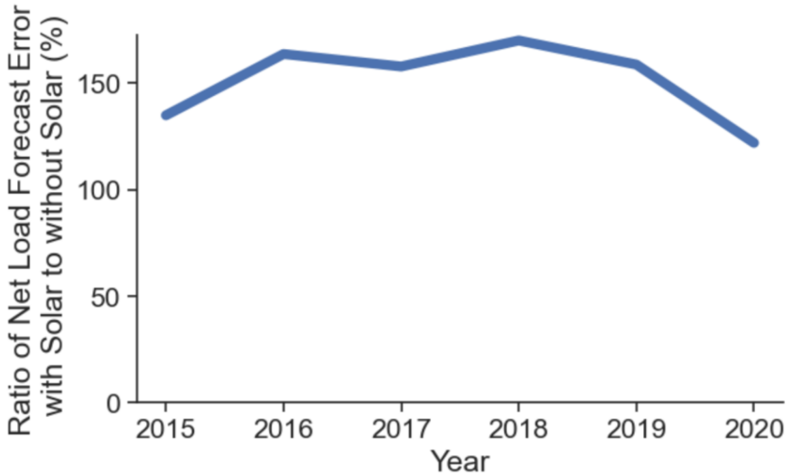


Price spikes beginning to occur at times of high solar ramps in CAISO

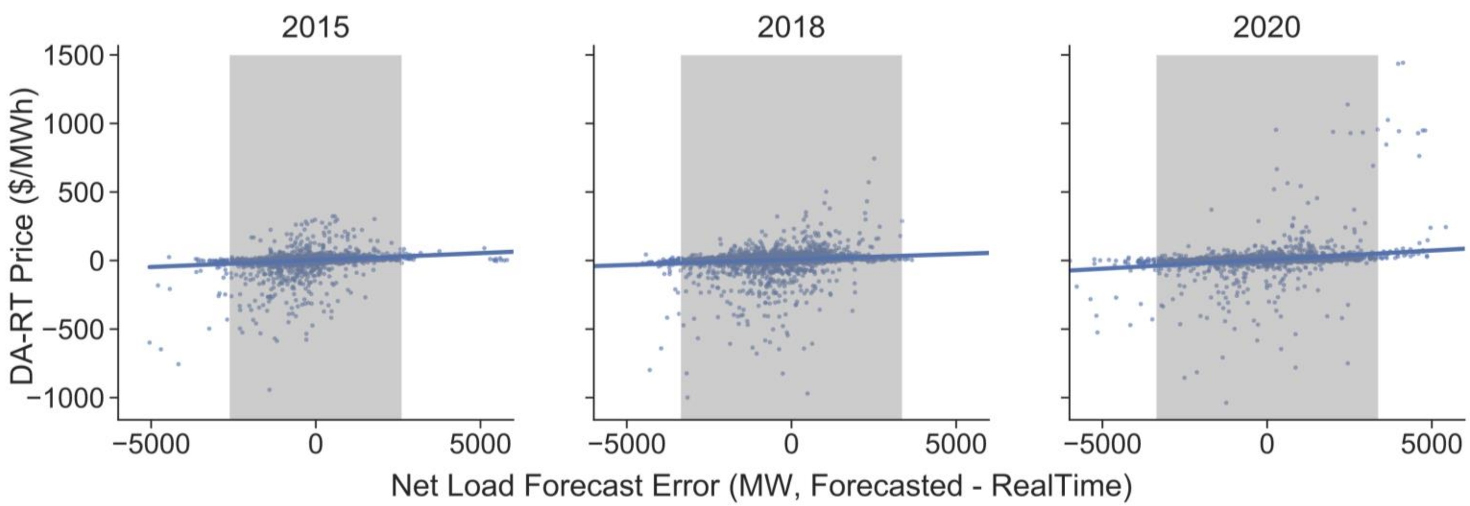


Solar forecast errors increase uncertainty between day-ahead market real-time markets in CAISO, though price impacts are limited

Higher day-ahead forecast errors due to solar in CAISO

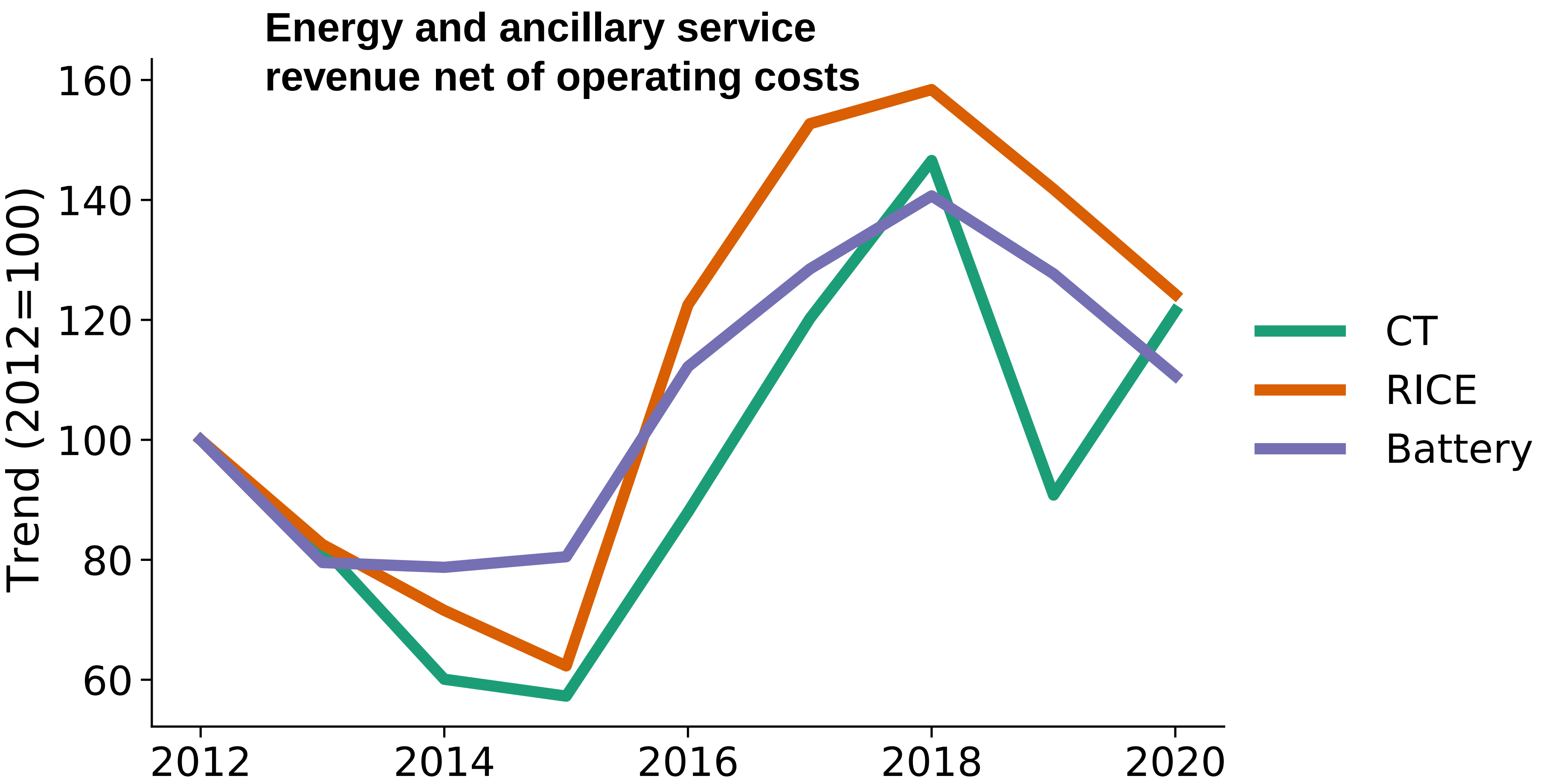


Little evidence that abnormally high net load forecast errors consistently drive extreme differences in the DA and RT prices



Note: The gray-shaded regions include 99% of all net load forecast errors without solar

Incentives to invest in flexible resources in CAISO increased since 2012, but the trend is unsteady

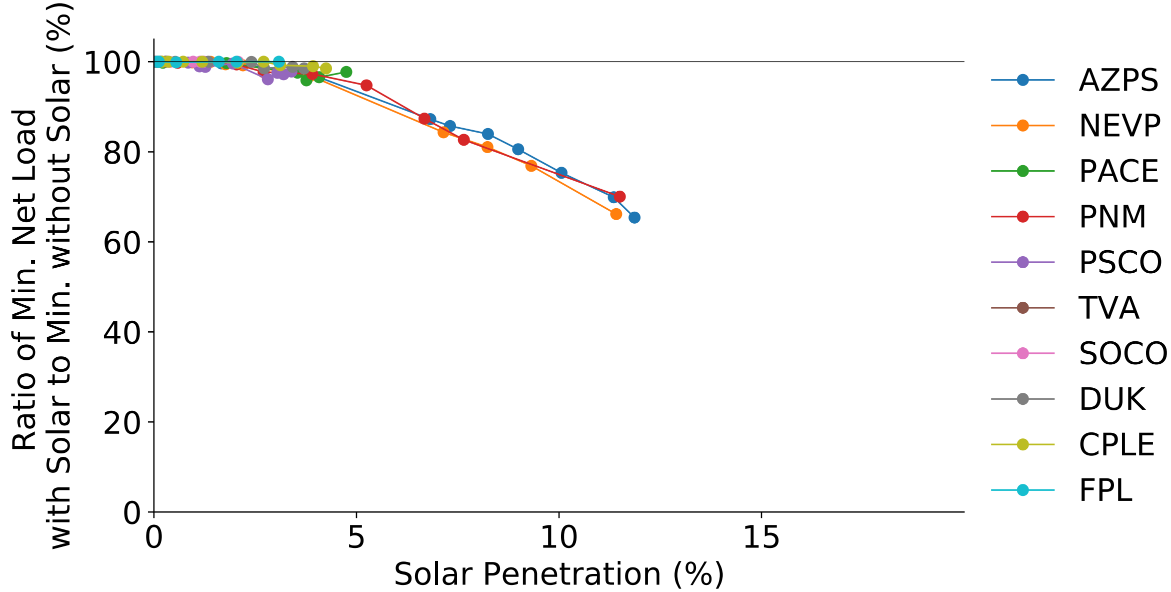


Note: Chart shows the trend in net revenue for each technology indexed to its level in 2012

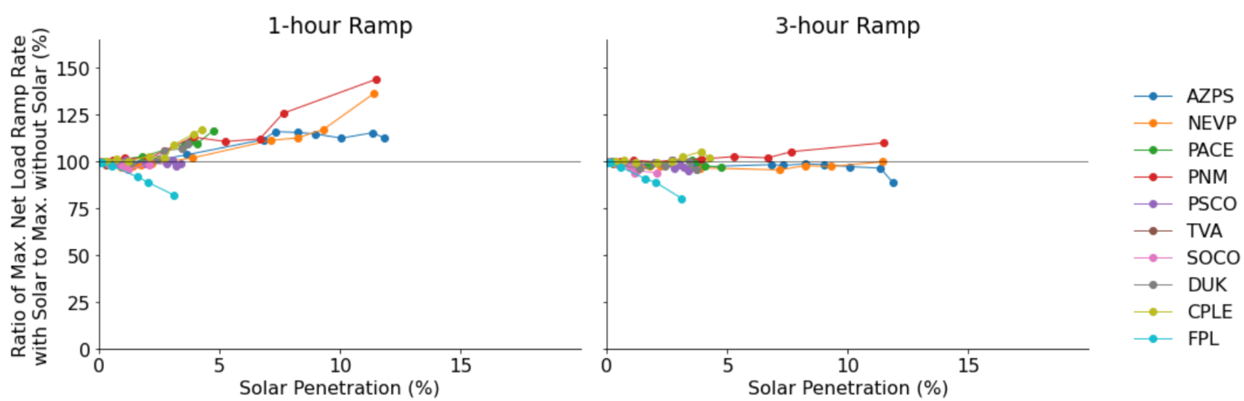
Solar is increasing the need for flexibility in some utilities outside of ISO/RTO regions

Lower minimum net load with solar in the Southwest

Solar growth shifted the minimum net load from nights to days in the spring and late fall



Higher net load ramp rates, especially in 1-hour net load ramps



Solar production on days of high risk of outages relative to average solar production in the same month

NERC System Risk Index (SRI): A high SRI indicates a day with severe challenges with generating and delivering power to U.S. loads

	Event Type	SRI	Date	CAISO	ERCOT	SPP	MISO	PJM	NYISO	ISO-NE
	Thunderstorm Derecho	8.87	2012-06-29				0.9	1.1	1.1	1.0
	Severe Weather	4.40	2015-06-30	0.8						
	Hurricane Isaias	3.72	2020-08-04					0.6	0.3	0.4
	Hurricane Laura	3.63	2020-08-27		1.3		0.9			
	Coincidental Generator Outages	3.49	2016-06-20	1.1		0.7	1.1	1.2		
	Severe Weather	3.38	2015-07-18	0.5			1.0			
	Thunderstorms/Showers	3.30	2015-07-20	0.8	1.0	0.9	0.9	1.1	1.1	1.0
	Wild fires	3.29	2020-09-07	0.8						
	Wild fires	3.29	2020-09-08	0.7						
	Severe Weather	3.24	2015-06-23					1.0	0.9	0.8
	Unrelated coincidental generator outages	3.22	2020-07-01	1.1			1.0	0.9	0.9	0.7
	Severe Weather	3.20	2015-07-13					0.9		
	Summer Weather	3.10	2015-07-30	0.8	1.0	1.0	1.1	0.8	0.7	0.7
	Severe Weather	3.06	2016-08-11					1.1		
Other Seasons	Polar Vortex	11.14	2014-01-07		0.9			1.6		
	Polar Vortex	8.02	2014-01-06		0.7			0.6		
	Hurricane Sandy	7.17	2012-10-30						0.5	0.5
	Hurricane Sandy	7.04	2012-10-29						0.2	0.2
	Storm, Flooding, Straightline Winds	4.45	2015-11-17	1.2						
	Winter Storm Riley	4.22	2018-03-02						0.1	0.1
	Winter Storm Grayson	4.06	2018-01-02		0.4	0.9	1.0	1.4	1.1	1.0
	Winter Storm Avery	4.05	2018-11-15					0.1	0.2	0.4
	Ice Storm and Hurricane Zeta	3.98	2020-10-28		1.0		0.6			
	Winter Storm Juno	3.86	2015-01-08						1.3	1.4
	Excessive Rainfall, Thunder/Lightning Storm	3.79	2015-10-23		0.5	0.6				
	Coincidental Generator Outages	3.61	2017-05-01					0.8		
	Arctic Outbreak	3.59	2020-01-12					0.9	1.0	0.9
	Hurricane Zeta	3.44	2020-10-29				0.7	0.2		
	Winter Storm	3.34	2019-02-24					0.4		
	Winter Storm Jayden	3.29	2019-01-30			1.3	1.3	1.6		
	Saddleridge Fire	3.25	2019-10-11	1.1						
	Winter Storm Indra	3.20	2019-01-21					1.7	1.2	1.1
	Winter Storms Quiana and Ryan	2.93	2019-02-25					1.8		
	Artic outbreak and extreme cold, thunderstorms	2.90	2020-01-11	1.0			0.6			

- Suggests solar, at least during daytime hours, often mitigates stressful periods in the summer
- Contributions of solar in the non-summer months are more mixed depending on the event

Other impacts of solar on the bulk power system

Inverter performance during disturbances

- NERC identified potential reliability issues associated with bulk power system-connected PV resources and their inverter settings
- Noted loss of solar generating resources during disturbances to the bulk power system
- Includes both tripping-related challenges and response to large voltage disturbances

Maintenance of adequate frequency response

- CAISO identified challenges with maintaining adequate frequency response as the share of inverter-based renewables increases
- CAISO contracts with neighboring utilities to transfer a portion of its frequency response obligation, actions are not included in market prices

Visibility and representation of DPV in operations and planning

- NERC identified gaps in representing the potential impacts of DER on the bulk power system
- Recommendations include:
  - Modeling these resources explicitly in planning studies rather than netting them with load
  - Improving representation of the resources in power system models and sharing data across the transmission and distribution interface

Summary

- Effects of solar growth on net load, wholesale prices, and solar's market value can readily be seen in California; effects are small in other organized markets where solar penetrations are at (ISO-NE) or below 5%
- California has low net load during spring days and high ramps as the sun sets in the evening, with similar patterns in real-time prices
- Negative prices during solar hours, price spikes in solar ramping hours, and higher prices for regulation down reserves all suggest growing challenges with providing flexibility, though broader shifts in the system can mitigate some of these challenges
- The decline in solar's wholesale market value in California has been matched by reductions in the cost of solar, thus maintaining solar's overall net-value proposition
- In many markets outside California, costs have often declined faster than market value, maintaining solar's overall competitive position.
- Impacts on prices can also increase the attractiveness of storage and other flexible resources to meet early-evening net-load peaks and ancillary service requirements

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For more information

Visit the project page to download the report, a briefing deck, and underlying data:
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